Kevin J. Nietmann
Plant General Manager
Calvert Cliffs Nuclear Power Plant
Constellation Generation Group, LLC

1650 Calvert Cliffs Parkway
Lusby, Maryland 20657
410 495-4101
410 495-4787 Fax

Constellation Energy Group

March 23, 2004

U.S. Nuclear Regulatory Commission
Washington, DC 20555

ATTENTION: Document Control Desk

SUBJECT: Calvert Cliffs Nuclear Power Plant
Unit No. 2; Docket No. 50-318; License No. DPR 69
Licensee Event Report 2004-001
Reactor Trip Due to Low Steam Generator Water Level After Feed Pump Trip

The attached report is being sent to you as required under 10 CFR 50.73 guidelines. Should you have questions regarding this report, we will be pleased to discuss them with you.

Very truly yours,

KJ Nietmann

KJN/JKK/bjd

Attachment: As stated

cc: J. Petro, Esquire
J. E. Silberg, Esquire
Director, Project Directorate I-1, NRC
G. S. Vissing, NRC
H. J. Miller, NRC
Resident Inspector, NRC
R. I. McLean, DNR

IE22

NRC FORM 366 (7-2001) U.S. NUCLEAR REGULATORY COMMISSION	APPROVED BY OMB NO. 3150-0104 EXPIRES 7-31-2004
LICENSEE EVENT REPORT (LER) (See reverse for required number of digits/characters for each block)	Estimated burden per response to comply with this mandatory information collection request: 50 hours. Reported lessons learned are incorporated into the licensing process and fed back to industry. Send comments regarding burden estimate to the Records Management Branch (T-6 E6), U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001, or by internet e-mail to bjs1@nrc.gov, and to the Desk Officer, Office of Information and Regulatory Affairs, NEOB-10202 (3150-0104), Office of Management and Budget, Washington, DC 20503. If a means used to impose information collection does not display a currently valid OMB control number, the NRC may not conduct or sponsor, and a person is not required to respond to, the information collection.

1. FACILITY NAME	2. DOCKET NUMBER	3. PAGE
Calvert Cliffs Nuclear Power Plant, Unit 2	05000 318	1 OF 10

4. TITLE

Reactor Trip Due to Low Steam Generator Water Level After Feed Pump Trip

5. EVENT DATE			6. LER NUMBER			7. REPORT DATE			8. OTHER FACILITIES INVOLVED	
MO	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REV NO	MO	DAY	YEAR	FACILITY NAME	DOCKET NUMBER 05000
01	23	04	2004	- 01 -	00	03	23	2004	FACILITY NAME	DOCKET NUMBER 05000

9. OPERATING MODE	1	11. THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check all that apply)							
			20.2201(b)		20.2203(a)(3)(ii)		50.73(a)(2)(ii)(B)		50.73(a)(2)(ix)(A)
10. POWER LEVEL	100		20.2201(d)		20.2203(a)(4)		50.73(a)(2)(iii)		50.73(a)(2)(x)
			20.2203(a)(1)		50.36(c)(1)(i)(A)	X	50.73(a)(2)(iv)(A)		73.71(a)(4)
			20.2203(a)(2)(i)		50.36(c)(1)(ii)(A)		50.73(a)(2)(v)(A)		73.71(a)(5)
			20.2203(a)(2)(ii)		50.36(c)(2)		50.73(a)(2)(v)(B)		OTHER Specify in Abstract below or in NRC Form 366A
			20.2203(a)(2)(iii)		50.46(a)(3)(ii)		50.73(a)(2)(v)(C)		
			20.2203(a)(2)(iv)		50.73(a)(2)(i)(A)		50.73(a)(2)(v)(D)		
			20.2203(a)(2)(v)		50.73(a)(2)(i)(B)		50.73(a)(2)(vii)		
			20.2203(a)(2)(vi)		50.73(a)(2)(i)(C)		50.73(a)(2)(viii)(A)		
			20.2203(a)(3)(i)		50.73(a)(2)(ii)(A)		50.73(a)(2)(viii)(B)		

12. LICENSEE CONTACT FOR THIS LER

NAME	TELEPHONE NUMBER (Include Area Code)
J. K. Kirkwood	410-495-2013

13. COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT

CAUSE	SYSTEM	COMPONENT	MANU-FACTURER	REPORTABLE TO EPIX	CAUSE	SYSTEM	COMPONENT	MANU-FACTURER	REPORTABLE TO EPIX
B	JK	RLY	A171	Y	B	JK	FUB		Y

14. SUPPLEMENTAL REPORT EXPECTED			15. EXPECTED SUBMISSION DATE	MONTH	DAY	YEAR
	YES (If yes, complete EXPECTED SUBMISSION DATE)	X NO				

16. ABSTRACT (Limit to 1400 spaces, i.e., approximately 15 single-spaced typewritten lines)

At 15:26 on January 23, 2004, Calvert Cliffs Unit 2 tripped from 100 percent power, initiated by the Reactor Protective System due to low steam generator water level caused by an erroneous over speed trip signal on the steam generator feed pump. The erroneous trip signal occurred because of a degraded digital speed monitor supply voltage caused by corrosion of an inline fuse and the fuse holder. The turbine bypass valves and atmospheric dump valves opened as designed, but the quick-open signal did not clear due to the failure of a relay in the reactor regulating circuit. The open valves resulted in over-cooling of the Reactor Coolant System, a Steam Generator Isolation Signal, and a Safety Injection Actuation Signal causing a loss of normal heat removal. During the recovery, a large insurge of subcooled water cooled the pressurizer, lowering reactor coolant pressure to produce a second Safety Injection Actuation Signal.

The corroded fuse, fuse holder, and failed relay were replaced. Operations staff was briefed on the effect of a large insurge of water on reactor coolant pressure, and Unit 2 was restarted and paralleled to the grid on January 25, 2004 at 21:53.

1. FACILITY NAME	2. DOCKET	6. LER NUMBER			3. PAGE
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
CALVERT CLIFFS, UNIT 2	05000 318	2004	- 001 -	00	02 OF 010

17. NARRATIVE *(If more space is required, use additional copies of NRC Form 366A)*

I. DESCRIPTION OF EVENT

At 15:26:37 on January 23, 2004, with Unit 2 operating at 100-percent power, 22 Steam Generator Feed Pump (SGFP) tripped due to an overspeed signal. With direction from the Control Room Supervisor the Control Room Operator attempted to reset 22 SGFP in accordance with the Abnormal Operating Procedure. The SGFP failed to reset after three attempts. At 100-percent power the Unit requires the operation of both SGFPs to maintain steam generator (SG) water level. Upon the loss of 22 SGFP the Operations Crew began to monitor the Reactor Coolant System (RCS) and SG level for trip criteria and depressed the manual reactor trip pushbuttons when the SG low water level pre-trip alarms were received. However, the automatic reactor trip signal was received approximately one second prior to the manual reactor trip signal (15:27:49). The Operations Crew entered the Emergency Operating Procedure (EOP) for Post-Trip Immediate Actions.

When the reactor tripped, the turbine bypass valves (TBV) and atmospheric dump valves (ADV) opened to the full-open position caused by the "quick open" signal provided to the valves. This "quick open" signal is generated to relieve stored energy in the secondary and primary systems and has the capacity for up to 45-percent rated thermal power. Once the stored energy is removed from the RCS the "quick open" signal is removed from the TBVs and ADVs allowing the TBVs to control RCS temperature at approximately 532 degrees Fahrenheit automatically.

The "quick open" signal to the TBVs and ADVs was not removed automatically, causing a rapid overcooling and reduction in pressure of the RCS and Main Steam (MS) system. An Auxiliary Feedwater Actuation Signal (AFAS) occurred at approximately 15:28:34, due to lowering SG water levels. Numbers 21 and 23 Auxiliary Feed Pumps started, as designed, to provide feedwater to the SGs.

At 15:28:52, a Safety Injection Actuation Signal (SIAS) was received, on low RCS pressure of approximately 1740 psia. The standby charging pumps started. Major plant equipment such as the 2A and 2B Diesel Generators (DG), High Pressure Safety Injection Pumps (HPSI), Low Pressure Safety Injection Pumps, and Containment Spray Pumps started. Reactor Coolant System pressure remained above the HPSI pump shutoff head throughout this event, such that the HPSI pumps did not inject into the RCS. The SIAS signal also secured RCS letdown and back-up pressurizer heaters. The Operations Crew secured two reactor coolant pumps per procedure requirements for receipt of a SIAS signal.

At 15:28:57 a Steam Generator Isolation Signal (SGIS) was received when SG pressure decreased to setpoint causing the Main Steam Isolation Valves (MSIVs) to shut. This isolated steam flow through the TBVs, slowing the rate of RCS cooldown. The shut MSIVs also removed the normal heat removal method for the plant.

At approximately nine minutes after the reactor trip, the Operations Crew transferred control of the ADVs to the Auxiliary Shutdown Panel to remove the "quick open" signal to the ADVs. Once ADV control was transferred to the Auxiliary Shutdown Panel, the ADVs closed to a predetermined position, terminating the overcooling and depressurization. Reactor Coolant System pressure was 1523 psia and the RCS temperature was 486 degrees Fahrenheit. Pressurizer level was below the indicating range of the level instrument.

Due to post-trip reactor decay heat, reactor coolant pumps' heat, residual heat contained within RCS piping, and operation of the charging pumps RCS temperature and pressure began to increase. At 15:39:50 pressurizer level instrumentation began to indicate a level increase as expected.

At 15:55 the Operations Crew transitioned to the EOP "Reactor Trip". With a SIAS still present, all charging pumps were running and RCS letdown was isolated. The Operations Crew took manual control of pressurizer main spray to control rising RCS pressure. Reactor Coolant System pressure was stabilized at 2318 psia at approximately 15:56. At 16:01:48 the Operations Crew removed 22 and 23 Charging Pumps from service because pressurizer level was still increasing (264 inches). At 16:06:50, 21 Charging Pump was secured. All injection had been stopped at this point. At 16:08 the Operations Crew secured the RCS heat-up at 515 degrees Fahrenheit. Reactor Coolant System pressure decreased to approximately 1800 psia as a result of the large insurge of subcooled water into the pressurizer.

The Operations Crew attempted to reset the SIAS to allow restoration of plant systems. Of specific interest to the crew was back-up pressurizer heaters needed to raise RCS pressure to normal value and RCS letdown control valves needed to lower pressurizer level to normal value. At 16:17:28 SIAS channel "A" was reset from the Control Room. The SIAS channel "B" would not reset from the Control Room. The Operations Crew was able to reset the SIAS "B" signal at the Engineered Safety Features Actuation System (ESFAS) cabinet located in the Cable Spreading Room at 16:27:36.

At 16:45 (with RCS pressure at 1782 psia) the Operations Crew began heating the RCS to return parameters to within the normal post-trip temperature band of 525-535 degrees Fahrenheit. Back-up pressurizer heaters, RCS letdown, and 21 Charging Pump were now in-service. Due to the large volume of subcooled water that had been added to the pressurizer, RCS pressure continued to slowly decrease despite having all pressurizer heaters in service.

At 17:18 a second SIAS actuation was received when RCS pressure reached approximately 1750 psia. At this point, RCS pressure stabilized at approximately 1745 psia for the next 30 minutes. To restore full pressurizer heater capacity the Operations Crew blocked and reset SIAS, in accordance with procedure, at 17:54. Pressurizer pressure began to recover.

At 18:25 SGIS was reset. At 18:30 AFAS resets were completed. At 18:33 charging and letdown were restored to operation with the RCS pressure at 2150 psia. At 19:26 the Operations Crew exited the EOP and implemented the appropriate Operating Procedures.

The unit was restarted and placed on the grid January 25, 2004 at 21:53, after the completion of the appropriate corrective actions.

II. CAUSES OF THE EVENT AND CORRECTIVE ACTIONS:

The causes of the Calvert Cliffs Unit 2 Reactor trip and the associated effects are as follow:

22 SGFP trip which resulted in the Unit 2 Reactor trip:

Cause:

1. Number 22 SGFP tripped due to degradation of voltage from the power source supplying the digital speed monitor which generated an erroneous trip signal to the SGFP controls trip circuit. The voltage degradation was caused by a voltage drop across the power supply in-line fuse due to corrosion on the contact surfaces. The corrosion was caused by high humidity in the control cabinet.

Contributing Causes:

1. A rigorous and systematic approach to recognizing and managing adverse local environmental conditions did not exist during the time that the SGFP control cabinets, with these fuse holders, were exposed to the local environment.

2. Abnormal environmental conditions that could affect equipment reliability were not recognized during the design phase when installing the fuses.

Corrective Actions:

1. All fuses and fuse holders in the Unit 2 SGFP control cabinets were replaced.

2. All fuses and fuse holders in the Unit 1 SGFP control cabinets were replaced.

3. Calvert Cliffs Procedure - "Calibration of Steam Generator Feed Pump Turbine (SGFPT) Speed Control System" will be revised to include:

   - Fuse holder resistance checks.
   - Fuse holder and fuse visual inspection for corrosion.
   - Removal and replacement of fuses several times to breakdown potential oxidation on the contact surfaces.
   - Checks of the air conditioning unit for proper operation of temperature and humidity control.

4. The appropriate Engineering Standard and procedures will be revised to include additional guidance on addressing localized environmental effects.

17. NARRATIVE *(If more space is required, use additional copies of NRC Form 366A)*

5. Procedures will be changed to ensure routine inspections are conducted for corrosion as part of routine maintenance practices while working on or within electrical equipment.

6. Leak Management Program procedures will be revised to include guidance to evaluate leaks for their effects on surrounding plant equipment.

7. Other trip-sensitive electronics susceptible to corrosion effects will be identified and corrective actions will be taken as necessary.

22 SGFP would not reset and start from the Control Room

Causes:

1. The inability to reset and start 22 SGFP was identified as a shift in the mechanical calibration of the Electric to Hydraulic (E/H) Converter which resulted in the Minimum Calibrated Control Oil Pressure setpoint being above the Latch Permissive setpoint (minimum control oil pressure to reset the turbine). The E/H Converter regulates control oil pressure to the SGFP turbine governor valve actuators to maintain the SGFP at the desired speed. The specific cause of the drift has not been determined, although the following causes are considered to be the most probable:

   - E/H Converter design inadequacies (Cannot hold calibration, difficult to calibrate, sensitive to control oil temperature changes).
   - E/H Converter lubricant is drying out-causing sticking.
   - Degradation of the E/H Converter mechanical components.

Corrective Actions:

1. Unit 2 E/H Converters were re-calibrated prior to startup.

2. Unit 1 E/H Converter calibrations were checked. Calibrations were within established limits.

3. The affected 22 SGFP Turbine E/H Converter will be replaced during the next Unit 2 Refueling Outage.

4. A revision to the E/H converter preventive maintenance (PM) has been made to check for setpoint drift and adequate lubrication. Based on results of the PM, corrective maintenance will be performed as required.

TBVs and ADVs would not re-close automatically, resulting in a SIAS and SGIS

Cause:

1. Inability to close the ADVs and the TBVs was caused by a normally open contact sticking closed in the K7 relay (Reactor Regulating System). Electric current in excess of the current for which the contact was designed caused burning and welding of the contact thereby fusing the contact closed. The K7 relay contacts are rated for 29 VDC, but were installed in a 125 VDC circuit in this application. K7 is an Allied Controls relay Model Number MHJLO-12A. The error occurred at an interface between two vendor designs: the Reactor Regulating System cabinet and the ADV/TBV control circuit.

Contributing Causes:

1. A modification was performed in 1993 that increased the load on the K7 contacts. The K7 relay contact current loading was doubled during the modification. The modification exacerbated the existing design inadequacy in the circuit. Corrective actions are not needed because the vendor oversight of design modifications has improved substantially since 1993. The extent of condition for relay design inadequacy was reviewed and found limited to this instance.

2. External and Internal Operating Experience (OE), if properly applied, may have prevented the K7 relay failure. (OE would not have identified the root cause of the failure - an under-rated K7 relay.) Additionally, Calvert Cliffs had a K1 coil failure in August 2003. Lack of clear and formal communications within Engineering resulted in no action being taken on the failure.

Corrective Actions:

1. All of the Unit 1 and Unit 2 K7 relays were replaced. Although the replacement relays are also not rated for the applied voltage, the relays were evaluated and determined to be acceptable for limited-duration use until the next outage of sufficient duration for modification.

2. Modifications are being developed to replace all K7 relays in both Unit 1 and Unit 2 with relays rated for use in the 125 VDC circuit.

3. Process improvements and training will be implemented to enhance the reviews of incoming OE items that contain multiple lessons learned and affect various site organizations or processes.

4. Internal Engineering communications concerning recommendations on equipment trends will be formalized.

17. NARRATIVE *(If more space is required, use additional copies of NRC Form 366A)*

SIAS 'B' Channel would not reset from the Control Room

Cause:

1. A wire going to terminal 7 of the containment hydrogen purge isolation hand-switch had come loose from its compression type terminal. This loose lead caused an open in the SIAS 'B' remote reset circuit thereby causing SIAS 'B' to not reset from the Control Room.

Contributing Cause:

1. The circuit had been modified during the 2003 Unit 2 refueling outage. This modification was installed to remove the SIAS contacts from the containment purge isolation circuits and one set of SIAS contacts from the hydrogen purge isolation circuits. The hand-switch is located in a very restricted location. It is surrounded by numerous wires, physical separation barriers, and other instruments. Multiple maintenance evolutions have occurred in the vicinity of this hand-switch, increasing the likelihood that inadvertent contact with the hand-switch wiring led to the loss of circuit continuity.

Corrective Actions:

1. The vendor of the hand-switch is Micro Switch. Based on vendor recommendation, Plant Engineering is processing a change to the Electrical Component Installation Standard to allow the use of ring lugs when performing wire terminations on compression style connections.

2. Electrical and Controls Section personnel will be trained on the changes to the Electrical Component Installation Standard once completion of the change is implemented.

An unplanned second SIAS actuation occurred while stabilizing the plant

Cause:

1. Initial SIAS actuation was reset before conditions were verified to be stable to ensure the SIAS would stay reset. During recovery from the plant cooldown, the pressurizer pressure rose to normal pressure and then began lowering. In order to gain control of plant equipment (pressurizer heaters and letdown) the SIAS was reset. Despite having all pressurizer heaters inservice, the large volume of subcooled water added to the pressurizer during the event caused the RCS pressure to continue lowering until a second, unplanned SIAS actuated.

Contributing Causes:

1. There was inadequate procedural guidance in the Immediate Post-Trip EOP. The procedure did not specify that the RCS temperature be maintained constant following an excessive cooldown. Approximately one-half of the insurge of RCS coolant into the pressurizer was caused by the controlled heatup of the RCS.

2. Delay in implementing an optimal recovery procedure caused delay in securing the running charging pumps. The Operations Crew was in the Immediate Post-Trip EOP for approximately 27 minutes. Approximately one-half of the insurge of RCS coolant into the pressurizer was caused by three charging pumps running due to SIAS.

Compensatory Actions:

1. Just-in-Time Tailgate training discussing key lessons-learned from this event was given to subsequent Operations Crews as they assumed their watch.

Corrective Actions:

1. Revisions to the EOP for ESFAS/AFAS reset steps will be made to include checking parameters (i.e., absolute value and trends) to ensure unplanned actuation does not recur.

2. Reset of valid ESFAS/AFAS and long-term recovery actions will be added to scenarios in the Licensed Operator Training Programs to enhance proficiencies at recovery and restoration actions.

3. Applicable procedures will be revised to ensure RCS Tcold is maintained approximately constant following termination of excessive RCS cooldown.

4. The Post-Trip Immediate Action procedure implementation methodology will be reviewed and compared with Industry practices.

5. Enhancements will be made to simulator training and evaluation to strengthen the methodology for implementing the EOPs.

6. Scenarios will be reviewed and training conducted in the Licensed Operator Training programs that exercise the optimal EOPs.

III. ANALYSIS OF EVENT

The 22 SGFP trip resulted in a partial loss of main feedwater flow and the Reactor Protective System (RPS) initiated an automatic trip of Unit 2 due to low SG water level. All reactor trip circuit breakers opened and all control rods fully inserted. When the reactor tripped, the ADVs and the TBVs opened and failed to shut when the conditions requiring their opening cleared. All other parameters were normal for the trip and all alarms that were received during the transient were expected. All equipment that received ESFAS signals actuated properly including the auxiliary feed pumps and the DG.

One non-safety-related bank of 300 kilowatt pressurizer backup heaters had 75 kilowatts of power previously disabled to allow better control of pressurizer pressure due to leaking of the pressurizer spray valve (2RC100F). Post-trip analysis demonstrated the disabled heaters and leaking spray valve did not have a significant impact on the recovery from the event.

The event resulted in automatic actuation of the RPS, safety injection, auxiliary feedwater, and DGs, and therefore is reported in accordance with 10 CFR 50.73(a)(2)(iv)(A). Immediate notification of the reactor trip and the SIAS (Event Number 40472) was made on January 23, 2004, in accordance with 10 CFR 50.72 (b)(2)(iv)(B) and 10 CFR 50.72(b)(3)(iv)(A), respectively. On January 26, 2004, after post-trip review of data revealed the reactor trip was an automatic trip and not a manual trip, a follow-up notification was made.

This event is reported in accordance with all of the following criteria:

10 CFR 50.73(a)(2)(iv)(A); "Any event or condition that resulted in manual or automatic actuation of any of the systems listed in paragraph (a)(2)(iv)(B) of this section,"

(a)(2)(iv)(B)The systems to which the requirements of paragraph (a)(2)(iv)(A) of this section apply are:

(1) Reactor Protective System (RPS) including reactor scram or reactor trip,
(3) Emergency Core Cooling Systems (ECCS) for pressurized-water reactors (PWRs) including: high-head, intermediate-head, and low-head injection systems and the low-head injection systems and low pressure injection function of residual (decay) heat removal systems.
(6) PWR auxiliary or emergency feedwater systems.
(8) Emergency AC electrical power systems, including: emergency diesel generators (EDGs)

There was also a SGIS resulting in the MSIVs closing and the subsequent loss of normal heat removal capability.

No actual nuclear safety consequences were incurred from this event; however, plant equipment malfunctions that occurred following the trip were as follows:

The "Quick-open" signal to the ADVs and the TBVs did not clear due to the malfunction of the K7 relay. Because the ADVs remained open, excess energy was removed from the RCS, over-cooling the system. The Probabilistic Risk Analysis results in an increase in frequency of 9E-06 to the Core Damage Frequency (CDF) and a less than 9E-07 increase in the Large Early Release Frequency (LERF).

Control Room Operators could not reset SIAS channel "B" due to a loose connection in the "B" remote reset circuit. The SIAS channel "B" was reset from the ESFAS cabinet in the Cable Spreading Room. The inability to reset the SIAS "B" channel from the Control Room did not deleteriously affect event recovery.

17. NARRATIVE *(If more space is required, use additional copies of NRC Form 366A)*

During the recovery phase of the event, RCS pressure decreased to a point that a second SIAS actuation occurred. The equipment normally cycled by a SIAS was already in its demand state with the exception of safety-related pressurizer heaters which cutoff, and letdown isolation valves which closed. A Probabilistic Risk Analysis of the second SIAS initiation indicated no contribution to CDF or LERF.

Plant safety margins, design basis limits, and Technical Specification cooldown rates were maintained during the event. All appropriate compensatory and corrective actions were completed prior to the plant restart.

V. ADDITIONAL INFORMATION

A. Component Failures

Component	IEEE 803 EIIS Function	IEEE 805 System ID
No. 22 SGFP Speed Control Power Supply Fuse	FUB	JK
Reactor Regulating System K7 Relay	RLY	JD

B. Previous Occurrences

A review of Calvert Cliffs' events over the past several years was performed. There were similar events identified involving plant trip on low SG water level after SGFP trip, but the cause of the pump trip was tied to a feedwater control circuit that is no longer in use. In 1991, Licensee Event Report No. 317/91-003 "Reactor Protection System Actuation and Plant Trip Due to Low Steam Generator Water Levels Caused by Loose Electrical Fuse" documents a Unit 1 trip on October 1, 1991 caused by a loose electrical fuse in the power supply to the 12 Feedwater Regulating Valve and the 12 SGFP turbine speed controller. The root cause was an improperly installed fuse in the power supply circuitry. The affected circuitry is no longer in use. The causal analysis describes a plant trip due to human performance problems: workers did not exercise adequate caution when installing fuses to prevent damage to the fuse holder. The damaged fuse holder was replaced, other similar applications were inspected, and personnel who manipulate fuses were trained to properly install and remove fuses. There were no plant trips caused by electrical problems from failing to adequately assess environmental conditions in the current SG feed water control circuit.